UNIT CORP
Form 10-Q
August 05, 2014
Table of Contents

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
[x] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2014
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
[Commission File Number 1-9260]
UNIT CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	73-1283193
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification No.)
7130 South Lewis, Suite 1000, Tulsa, Oklahoma	74136
(Address of principal executive offices)	(Zip Code)

(918) 493-7700
(Registrant’s telephone number, including area code)
None
(Former name, former address and former fiscal year,
if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [x] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [x] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [x]

As of July 25, 2014, 49,583,543 shares of the issuer's common stock were outstanding.

Table of Contents

TABLE OF CONTENTS

1

Table of Contents

Forward-Looking Statements

This report contains "forward-looking statements" – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document that addresses activities, events or developments that we expect or anticipate will or may occur in the future, are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "pre
and similar expressions are used to identify forward-looking statements. This report modifies and supersedes documents filed by us before this report. In addition, certain information that we file with the SEC in the future will automatically update and supersede information contained in this report.

These forward-looking statements include, among others, such things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells we plan to drill or rework;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;
- our ability to transport or convey our oil or natural gas production to established pipeline systems;
- impact of federal and state legislative and regulatory actions impacting our costs and increasing operating restrictions or delays as well as other adverse impacts on our business;
- our projected production guidelines for the year;
- our anticipated capital budgets;
- the number of wells our oil and natural gas segment plans to drill during the year; and
- our outlook for the demand of our new drilling rig, the BOSS drilling rig.

These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, and expected future developments, as well as other factors we believe are appropriate in the circumstances. Whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties, any one or combination of which could cause our actual results to differ materially from our expectations and predictions, including:

- the risk factors discussed in this document and in the documents (if any) we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature of (or lack of) business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases in commodity prices; and

- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this document to reflect the occurrence of unanticipated events.

Table of Contents

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	June 30, 2014	December 31, 2013
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,078	$ 18,593
Accounts receivable, net of allowance for doubtful accounts of $2,120 and $5,342 at June 30, 2014 and at December 31, 2013, respectively	177,149	139,788
Materials and supplies	8,540	10,998
Current derivative asset (Note 9)	—	515
Current deferred tax asset	13,585	13,585
Assets held for sale	—	15,621
Prepaid expenses and other	10,914	12,931
Total current assets	211,266	212,031
Property and equipment:		
Oil and natural gas properties on the full cost method:		
Proved properties	4,544,173	4,235,712
Unproved properties not being amortized	555,434	545,588
Drilling equipment	1,526,923	1,477,093
Gas gathering and processing equipment	592,191	549,422
Transportation equipment	40,301	39,666
Other	101,452	87,435
	7,360,474	6,934,916
Less accumulated depreciation, depletion, amortization, and impairment	3,380,809	3,212,225
Net property and equipment	3,979,665	3,722,691
Debt issuance cost	11,050	11,844
Goodwill	62,808	62,808
Other assets	12,893	13,016
Total assets	$ 4,277,682	$ 4,022,390

The accompanying notes are an integral part of these
unaudited condensed consolidated financial statements.

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED) - CONTINUED

	June 30, 2014	December 31, 2013
	(In thousands except share amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 207,613	$ 154,062
Accrued liabilities (Note 4)	65,744	64,363
Income taxes payable	10,776	7,474
Current derivative liabilities (Note 9)	15,839	5,561
Current portion of other long-term liabilities (Note 5)	14,578	12,113
Total current liabilities	314,550	243,573
Long-term debt (Note 5)	645,925	645,696
Non-current derivative liabilities (Note 9)	326	—
Other long-term liabilities (Note 5)	168,796	158,331
Deferred income taxes	853,398	801,398
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $.20 par value, 175,000,000 shares authorized, 49,584,080 and 49,107,004 shares issued, respectively	9,729	9,659
Capital in excess of par value	455,390	445,470
Retained earnings	1,829,568	1,718,263
Total shareholders' equity	2,294,687	2,173,392
Total liabilities and shareholders' equity	$ 4,277,682	$ 4,022,390

The accompanying notes are an integral part of these
unaudited condensed consolidated financial statements.

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands except per share amounts)			
Revenues:				
Oil and natural gas	$198,498	$164,799	$386,705	$318,408
Contract drilling	114,278	105,005	220,878	212,533
Gas gathering and processing	92,655	70,617	185,836	128,012
Total revenues	405,431	340,421	793,419	658,953
Expenses:				
Oil and natural gas:				
Operating costs	44,723	44,994	85,138	88,032
Depreciation, depletion, and amortization	71,245	55,335	130,925	107,318
Contract drilling:				
Operating costs	66,494	63,590	130,298	129,592
Depreciation	20,239	17,908	38,634	35,168
Gas gathering and processing:				
Operating costs	78,648	59,557	159,608	108,967
Depreciation and amortization	10,109	8,214	19,700	15,370
General and administrative	10,600	9,679	20,237	18,352
Gain on disposition of assets	(195)	(3,483)	(9,621)	(3,399)
Total operating expenses	301,863	255,794	574,919	499,400
Income from operations	103,568	84,627	218,500	159,553
Other income (expense):				
Interest, net	(4,131)	(4,591)	(7,921)	(8,152)
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	(10,709)	16,344	(29,075)	10,420
Other	(49)	(91)	71	(157)
Total other income (expense)	(14,889)	11,662	(36,925)	2,111
Income before income taxes	88,679	96,289	181,575	161,664
Income tax expense:				
Current	8,475	2,117	18,270	4,634
Deferred	25,844	35,165	52,000	57,817
Total income taxes	34,319	37,282	70,270	62,451
Net income	$54,360	$59,007	$111,305	$99,213
Net income per common share:				
Basic	$1.12	$1.22	$2.29	$2.06
Diluted	$1.11	$1.22	$2.27	$2.05

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Net income	$54,360	$59,007	$111,305	$99,213
Other comprehensive income (loss), net of taxes:				
Change in value of derivative instruments used as cash flow hedges, net of tax of $0, $3,874, $0, and ($2,504)	—	6,091	—	(3,820)
Reclassification - derivative settlements, net of tax of $0, $317, $0, and ($1,177)	—	506	—	(1,831)
Ineffective portion of derivatives, net of tax of $0, ($667), $0, and ($141)	—	(1,050)	—	(227)
Comprehensive income	$54,360	$64,554	$111,305	$93,335

The accompanying notes are an integral part of these
unaudited condensed consolidated financial statements.

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended June 30, 2014	2013
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$111,305	$99,213
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	190,813	159,369
(Gain) loss on derivatives	29,075	(13,429)
Cash (payments) receipts on derivatives settled	(17,955)	3,868
Deferred tax expense	52,000	57,817
Gain on disposition of assets	(9,621)	(3,399)
Employee stock compensation plans	11,655	10,654
Other, net	3,076	3,005
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(45,150)	(13,001)
Accounts payable	(11,585)	2,219
Material and supplies	2,458	(751)
Accrued liabilities	7,440	11,313
Other, net	2,017	1,010
Net cash provided by operating activities	325,528	317,888
INVESTING ACTIVITIES:		
Capital expenditures	(420,235)	(339,300)
Proceeds from disposition of assets	40,825	16,829
Other	303	—
Net cash used in investing activities	(379,107)	(322,471)
FINANCING ACTIVITIES:		
Borrowings under credit agreement	129,300	183,900
Payments under credit agreement	(129,300)	(185,000)
Net payments on capitalized leases	(711)	—
Proceeds from exercise of stock options	887	81
Book overdrafts	35,888	5,669
Net cash provided by financing activities	36,064	4,650
Net increase (decrease) in cash and cash equivalents	(17,515)	67
Cash and cash equivalents, beginning of period	18,593	974
Cash and cash equivalents, end of period	$1,078	$1,041
Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Interest paid (net of capitalized)	6,223	6,273
Income taxes	15,800	7,100
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	(29,247)	28,615
Non-cash additions to oil and natural gas properties related to asset retirement obligations	(15,432)	(11,945)
Non-cash additions to property, plant, and equipment acquired under capital leases	(26,510)	—

The accompanying notes are an integral part of these
unaudited condensed consolidated financial statements.

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited condensed consolidated financial statements in this report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms “company,” “Unit,” “we,” “our,” “us,” or like terms refer to Unit Corporation, a Delaware corporation, and, as appropriate, one or more of its subsidiaries and affiliates, except as otherwise indicated or as the context otherwise requires.

The accompanying condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements. This report should be read in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 25, 2014, for the year ended December 31, 2013.

In the opinion of our management, the accompanying unaudited condensed consolidated financial statements contain all normal recurring adjustments (including the elimination of all intercompany transactions) necessary to fairly state the following:

• Balance Sheets at June 30, 2014 and December 31, 2013;
• Statements of Income for the three and six months ended June 30, 2014 and 2013;
• Statements of Comprehensive Income for the three and six months ended June 30, 2014 and 2013; and
• Statements of Cash Flows for the six months ended June 30, 2014 and 2013.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our unaudited condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the six months ended June 30, 2014 and 2013 are not necessarily indicative of the results to be realized for the full year in the case of 2014, or that we realized for the full year of 2013.

Certain amounts in the accompanying unaudited condensed consolidated financial statements for prior periods have been reclassified to conform to current year presentation. Certain financial statement captions were expanded or combined with no impact to consolidated net income or shareholders' equity.

With respect to the unaudited financial information for the three and six month periods ended June 30, 2014 and 2013, our auditors, PricewaterhouseCoopers LLP, reported that it applied limited procedures in accordance with professional standards in reviewing that information. Its separate report dated August 5, 2014, which is included in this report, states that it did not audit and it does not express an opinion on that unaudited financial information. Accordingly, the degree of reliance placed on its report should be restricted in light of the limited review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 (Act) for its report on the unaudited financial information because that report is not a “report” or a “part” of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

NOTE 2 – DIVESTITURES

We sold non-core oil and natural gas assets, net of related expenses, for $11.3 million during the first six months of 2014. Proceeds from those dispositions reduced the net book value of our full cost pool with no gain or loss recognized.

During the first quarter of 2014, we sold four idle 3,000 horsepower drilling rigs to an unaffiliated third-party. These drilling rigs were previously classified as assets held for sale at December 31, 2013. The proceeds of this sale, less costs to sell, exceeded the $16.3 million net book value of the drilling rigs, both in the aggregate and for each drilling rig, resulting in a gain of $9.6 million.

During the second quarter of 2013, we sold one 2,000 horsepower electric drilling rig to an unaffiliated third-party.

Table of Contents

NOTE 3 – EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended June 30, 2014			
Basic earnings per common share	$54,360	48,642	$1.12
Effect of dilutive stock options, restricted stock, and stock appreciation rights (SARs)	—	474	(0.01)
Diluted earnings per common share	$54,360	49,116	$1.11
For the three months ended June 30, 2013			
Basic earnings per common share	$59,007	48,208	$1.22
Effect of dilutive stock options, restricted stock, and SARs	—	298	—
Diluted earnings per common share	$59,007	48,506	$1.22

The following table shows the number of stock options and SARs (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended June 30,	
	2014	2013
Stock options and SARs	24,500	250,901
Average exercise price	$73.26	$52.72

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the six months ended June 30, 2014			
Basic earnings per common share	$111,305	48,568	$2.29
Effect of dilutive stock options, restricted stock, and SARs	—	442	(0.02)
Diluted earnings per common share	$111,305	49,010	$2.27
For the six months ended June 30, 2013			
Basic earnings per common share	$99,213	48,162	$2.06
Effect of dilutive stock options, restricted stock, and SARs	—	329	(0.01)
Diluted earnings per common share	$99,213	48,491	$2.05

	Six Months Ended June 30,	
	2014	2013
Stock options and SARs	49,000	149,665
Average exercise price	$67.83	$58.41

Table of Contents

NOTE 4 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	June 30, 2014	December 31, 2013
	(In thousands)	
Employee costs	$21,440	$27,633
Lease operating expenses	16,503	16,073
Taxes	9,166	2,313
Interest	6,519	6,504
Derivative settlements	2,369	416
Deposits on assets held for sale	—	3,750
Other	9,747	7,674
Total accrued liabilities	$65,744	$64,363

NOTE 5 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

As of the dates in the table, our long-term debt consisted of the following:

	June 30, 2014	December 31, 2013
	(In thousands)	
Credit agreement	$—	$—
6.625% senior subordinated notes due 2021, net of unamortized discount of $4.1 million at June 30, 2014 and $4.3 million at December 31, 2013	645,925	645,696
Total long-term debt	$645,925	$645,696

Credit Agreement. Under our Senior Credit Agreement (credit agreement), the amount available to be borrowed is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount of $900.0 million. Our current commitment amount is $500.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. The credit agreement matures as of September 13, 2016. In connection with the most recent amendment of the credit agreement, we paid $1.5 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement.

The amount of the borrowing base–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. Effective with the April 2014 redetermination, the lenders of our credit agreement approved an increase in our borrowing base to $900.0 million from $800.0 million. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the credit agreement that in any event cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at anytime, without a premium or penalty. At June 30, 2014, we had no outstanding borrowings under our credit agreement.

Table of Contents

We can use borrowings for financing general working capital requirements for (a) exploration, development, production, and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of June 30, 2014, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. We have an aggregate principal amount of $650.0 million, 6.625% senior subordinated notes (the Notes). The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021. In connection with the issuance of the Notes, we incurred $14.7 million of fees that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantor, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors, and the Trustee (as supplemented, the 2011 Indenture), establishing the terms and providing for the issuance of the Notes. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

The Notes are guaranteed by our 100% owned domestic direct and indirect subsidiaries (the Guarantors). Unit, as the parent company, has no independent assets or operations. These guarantees (registered under the registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the 2011 Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from any of our subsidiaries through dividends, loans, advances, or otherwise.

At any time before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of June 30, 2014.

Table of Contents

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	June 30, 2014	December 31, 2013
	(In thousands)	
Asset retirement obligation (ARO) liability	$120,591	$133,657
Capital lease obligations	25,799	—
Workers’ compensation	18,868	20,041
Separation benefit plans	10,357	9,382
Deferred compensation plan	3,984	3,589
Gas balancing liability	3,775	3,775
	183,374	170,444
Less current portion	14,578	12,113
Total other long-term liabilities	$168,796	$158,331

Estimated annual principal payments under the terms of debt and other long-term liabilities during each of the five successive twelve month periods beginning July 1, 2014 (and through 2018) are $14.6 million, $38.8 million, $9.6 million, $7.2 million, and $7.4 million, respectively.

Capital Leases

During the second quarter, our mid-stream segment entered into capital lease agreements for twenty compressors with initial terms of seven years. The underlying assets are included in gas gathering and processing equipment. The current portion of our capital lease obligations of $3.1 million is included in current portion of other long-term liabilities and the non-current portion of $22.7 million is included in other long-term liabilities in the accompanying Unaudited Condensed Consolidated Balance Sheets as of June 30, 2014. These capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining related to these leases are $12.3 million and $4.2 million, respectively at June 30, 2014. Annual payments, net of maintenance and interest, average $4.1 million annually through 2021. At the end of the term, our mid-stream segment has the option to purchase the assets at 10% of the fair market value of the assets at that time.

Future payments required under the capital leases at June 30, 2014 are as follows:

Ending June 30,	Amount (In thousands)
2015	$6,134
2016	6,195
2017	6,195
2018	6,195
2019	6,195
2020 and thereafter	13,065
Total future payments	43,979
Less payments related to:	
Maintenance	12,285
Interest	4,196
Signed contract effective September 2014	1,699
Present value of future minimum payments	$25,799

Table of Contents

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets. Our oil and natural gas wells are plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The plugging and abandonment liability for a well is recorded in the period in which the obligation is incurred (at the time the well is drilled or acquired). None of our assets are restricted for purposes of settling these AROs. All of our AROs relate to the plugging costs associated with our oil and gas wells.

The following table shows certain information about our AROs for the periods indicated:

	Six Months Ended June 30,	
	2014	2013
	(In thousands)	
ARO liability, January 1:	$133,657	$146,159
Accretion of discount	2,366	2,825
Liability incurred	1,900	2,869
Liability settled	(1,917)	(3,192)
Liability sold	(877)	(324)
Revision of estimates [1]	(14,538)	(11,298)
ARO liability, June 30:	120,591	137,039
Less current portion	3,118	2,948
Total long-term ARO	$117,473	$134,091

(1) Plugging liability estimates were revised in both 2014 and 2013 for updates in the cost of services used to plug wells over the preceding year. We had various upward and downward adjustments.

NOTE 7 – NEW ACCOUNTING PRONOUNCEMENTS

Compensation - Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide that a Performance Target Could Be Achieved after the Requisite Service Period. The FASB has issued ASU 2014-12, the amendments in the ASU require that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. A reporting entity should apply existing guidance in Topic 718, Compensation – Stock Compensation, as it relates to awards with performance conditions that affect vesting to account for such awards. The performance target should not be reflected in estimating the grant-date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved.The amendments in this ASU are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Earlier adoption is permitted. We do not have any stock compensation awards with these conditions at this time.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early application is not permitted. We are in the process of evaluating the impact it will have on our financial statements.

Table of Contents

Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The FASB has issued ASU 2014-08, the amendments in this update change the criteria for reporting discontinued operations while enhancing disclosures in this area. It also addresses sources of confusion and inconsistent application related to financial reporting of discontinued operations guidance in U.S. GAAP. Under the new guidance, only disposals representing a strategic shift that would have a major effect on the organization's operations and financial results should be presented as discontinued operations. In addition, it requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. It also requires disclosure of pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. The updates are effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. Early adoption is permitted. We currently do not have any discontinued operations or disposals of components of an entity.

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. In July 2013, ASU 2013-11 was issued because GAAP does not include explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendment provides explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendments in this update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The amendments are applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. There was no effect on our financial position or results of operations when adopted.

NOTE 8 – STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Recognized stock compensation expense	$4.5	$4.3	$8.3	$7.6
Capitalized stock compensation cost for our oil and natural gas properties	1.0	0.9	1.8	1.6
Tax benefit on stock based compensation	1.7	1.6	3.2	2.9

The remaining unrecognized compensation cost related to unvested awards at June 30, 2014 is approximately $27.4 million of which $4.5 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 of a year.

The Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (the amended plan) allows us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) as well as to non-employee directors. A total of 3,300,000 shares of the company's common stock is authorized for issuance to eligible participants under the amended plan.

Table of Contents

We did not grant any SARs or stock options during either of the three or six month periods ending June 30, 2014 and 2013. The following table shows the fair value of any restricted stock awards granted to employees and non-employee directors during the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Shares granted:				
Employees	—	—	438,342	448,549
Non employee directors	13,768	21,128	13,768	21,128
	13,768	21,128	452,110	469,677
Estimated fair value (in millions):				
Employees	$—	$—	$22.4	$21.0
Non employee directors	0.9	0.9	0.9	0.9
	$0.9	$0.9	$23.3	$21.9
Percentage of shares granted expected to be distributed:				
Employees	N/A	N/A	95 %	94 %
Non employee directors	100 %	100 %	100 %	100 %

The restricted stock awards granted during the first three and six months of 2014 and 2013 are being recognized over a three year vesting period, except for a portion of those awards made to certain executive officers. As to those executive officers, 40% of the shares granted in 2014, or 71,674 shares, and 30% of the shares granted in 2013, or 57,405 shares, (the performance shares), will cliff vest in the first half of 2017 and 2016, respectively. The actual number of performance shares that vest in 2016 and 2017 will be based on the company's achievement of certain stock performance measures at the end of the term, and will range from 0% to 150% of the restricted shares granted as performance shares. Based on the selected performance criteria, the participants are estimated to receive the targeted amount (or approximately 100%) of the 2014 and 2013 performance based shares. The total aggregate stock compensation expense and capitalized cost related to oil and natural gas properties for 2014 awards for the first six months of 2014 was $4.3 million.

NOTE 9 – DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs, and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type, and quantity of our production subject to a derivative contract is based, in part, on our view of current and future market conditions. As of June 30, 2014, our derivative transactions consisted of the following types of hedges:

- Swaps. We receive or pay a fixed price for the commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- Collars. A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

We have documented policies and procedures to monitor and control the use of derivative transactions. We do not engage in derivative transactions for speculative purposes. In August 2012, we determined–on a prospective basis–that we would no longer elect to use cash flow hedge accounting for our economic hedges. As a result, the change in fair value, on all commodity derivatives entered into after that determination, is reflected in the income statement and not in accumulated other comprehensive income (OCI). As of December 31, 2013, all cash flow hedges had expired.

Table of Contents

At June 30, 2014, the following non-designated hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul'14 – Dec'14	Crude oil – swap	3,000 Bbl/day	$91.77	WTI – NYMEX
Jul'14 – Dec'14	Crude oil – collar	4,000 Bbl/day	$90.00-96.08	WTI – NYMEX
Jan'15 – Dec'15	Crude oil – swap	1,000 Bbl/day	$95.00	WTI – NYMEX
Jul'14 – Dec'14	Natural gas – swap	80,000 MMBtu/day	$4.24	NYMEX (HH)
Jul'14 – Dec'14	Natural gas – collar	10,000 MMBtu/day	$3.75-4.37	NYMEX (HH)

The following tables present the fair values and locations of the derivative transactions recorded in our Unaudited Condensed Consolidated Balance Sheets:

	Balance Sheet Location	Derivative Assets Fair Value June 30, 2014 (In thousands)	December 31, 2013
Commodity derivatives:			
Current	Current derivative asset	$—	$515
Long-term	Non-current derivative asset	—	—
Total derivative assets		$—	$515

	Balance Sheet Location	Derivative Liabilities Fair Value June 30, 2014 (In thousands)	December 31, 2013
Commodity derivatives:			
Current	Current derivative liabilities	$15,839	$5,561
Long-term	Non-current derivative liabilities	326	—
Total derivative liabilities		$16,165	$5,561

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets.

We recognized in OCI the effective portion of any changes in fair value and reclassified the recognized gains (losses) on the sales to oil and natural gas revenue as the underlying transactions were settled. Because our cash flow hedges expired as of December 31, 2013, we had no balance in accumulated OCI at June 30, 2014. As of June 30, 2013, we had recognized a gain of $1.7 million, net of tax.

For our economic hedges that we did not apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net in our Unaudited Condensed Consolidated Statements of Income. Changes in the fair value of derivatives that were designated as cash flow hedges, to the extent they were effective in offsetting cash flows attributable to the hedged risk, were recorded in OCI until the hedged item was recognized into earnings. When the hedged item was recognized into earnings, it was reported in oil and natural gas revenues. Any change in fair value that resulted from ineffectiveness was recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net.

16

Table of Contents

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Income (cash flow hedges) for the six months ended June 30:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) (1)	
	2014	2013
	(In thousands)	
Commodity derivatives	$—	$1,709

(1) Net of taxes.

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Income (cash flow hedges) for the three months ended June 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2014	2013	2014	2013
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$—	$(823)	$—	$—
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	—	—	—	1,717
Total		$—	$(823)	$—	$1,717

(1) Effective portion of gain (loss).
(2) Ineffective portion of gain (loss).

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Income (derivatives not designated as hedging instruments) for the three months ended June 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2014	2013
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net (1)	$(10,709)	$14,627
Total		$(10,709)	$14,627

(1) Amounts settled during the 2014 and 2013 periods include losses of $(9.1) million and $(0.2) million, respectively.

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Income (cash flow hedges) for the six months ended June 30:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2014	2013	2014	2013
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$—	$3,008	$—	$—
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	—	—	—	368
Total		$—	$3,008	$—	$368

(1) Effective portion of gain (loss).
(2) Ineffective portion of gain (loss).

Table of Contents

Effect of derivative instruments on the Unaudited Condensed Consolidated Statements of Income (derivatives not designated as hedging instruments) for the six months ended June 30:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain of (Loss) Recognized in Income on Derivative	
		2014	2013
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net (1)	$(29,075)	$10,052
Total		$(29,075)	$10,052

(1) Amounts settled during the 2014 and 2013 periods include a loss of $(18.0) million and a gain of $0.9 million, respectively.

NOTE 10 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value. The highest priority is given to Level 1 and the lowest priority is given to Level 3. The levels are summarized as follows:

- Level 1 - unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2 - significant observable pricing inputs other than quoted prices included within level 1 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3 - generally unobservable inputs that are developed based on the best information available and may include our own internal data.

The inputs available to us determine the valuation technique we use to measure the fair values of our financial instruments. We corroborate these inputs based on recent transactions and broker quotes and compare the fair value with actual settlements.

Table of Contents

The following tables set forth our recurring fair value measurements:

	June 30, 2014				
	Level 2	Level 3	Gross Amounts	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$—	$—	$—	$—	$—
Liabilities	(10,084)	(6,081)	(16,165)	—	(16,165)
	$(10,084)	$(6,081)	$(16,165)	$—	$(16,165)

	December 31, 2013				
	Level 2	Level 3	Gross Amounts	Effect of Netting	Net Amounts Presented
	(In thousands)				
Financial assets (liabilities):					
Commodity derivatives:					
Assets	$1,978	$20	$1,998	$(1,483)	$515
Liabilities	(4,429)	(2,615)	(7,044)	1,483	(5,561)
	$(2,451)	$(2,595)	$(5,046)	$—	$(5,046)

All of our counterparties are subject to master netting arrangements. If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty. We are not required to post cash collateral with our counterparties.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 2 Fair Value Measurements

Commodity Derivatives. We measure the fair values of our crude oil and natural gas swaps using estimated internal discounted cash flow calculations based on the NYMEX futures index.

Level 3 Fair Value Measurements

Commodity Derivatives. The fair values of our natural gas and crude oil collars are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms, or quotes obtained from counterparties to the agreements.

Table of Contents

The following tables are reconciliations of our level 3 fair value measurements:

	Commodity Collars			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Beginning of period	$(4,464)	$(2,536)	$(2,595)	$(595)
Total gains or losses (realized and unrealized):				
Included in earnings [1]	(4,401)	3,346	(7,829)	1,405
Included in other comprehensive income (loss)	—	—	—	—
Settlements	2,784	636	4,343	636
End of period	$(6,081)	$1,446	$(6,081)	$1,446
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$(1,617)	$3,982	$(3,486)	$2,041

(1) Commodity collars are reported in the Unaudited Condensed Consolidated Statements of Income in oil and natural gas revenues (for cash flow hedges) and gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net, respectively.

The following table provides quantitative information about our Level 3 unobservable inputs at June 30, 2014:

Commodity [1]	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Oil collars	$(5,674)	Discounted cash flow	Forward commodity price curve	$0.06 - $10.27
Natural gas collar	$(407)	Discounted cash flow	Forward commodity price curve	$0.00 - $0.40

(1) The commodity contracts detailed in this category include non-exchange-traded crude oil and natural gas collars that are valued based on NYMEX. The forward pricing range represents the low and high price expected to be paid or received within the settlement period.

Based on our valuation at June 30, 2014, we determined that risk of non-performance by our counterparties was immaterial.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop these estimates. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At June 30, 2014, the carrying values on the Unaudited Condensed Consolidated Balance Sheets for cash and cash equivalents (classified as Level 1), accounts receivable, accounts payable, other current assets, and current liabilities approximate their fair value because of their short term nature.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and also considering the risk of our non-performance, long-term debt under our credit agreement has historically approximated its fair value and at June 30, 2014 was zero. This debt would be classified as Level 2.

The carrying amounts of long-term debt, net of unamortized discount, associated with the Notes reported in the Unaudited Condensed Consolidated Balance Sheets as of June 30, 2014 and December 31, 2013 were $645.9 million and $645.7 million, respectively. We estimated the fair value of these Notes using quoted marked prices at June 30, 2014 and December 31, 2013 which were $695.5 million and $688.2 million, respectively. These Notes would be classified as Level 2.

Fair Value of Non-Financial Instruments

The initial measurement of AROs at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant, and equipment. Significant Level 3 inputs used in the

Table of Contents

calculation of AROs include plugging costs and remaining reserve lives. A reconciliation of the Company’s AROs is presented in Note 6 – Asset Retirement Obligations.

NOTE 11 – ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

There was no activity in accumulated other comprehensive income in 2014.

Changes in accumulated other comprehensive income (loss) by component, net of tax, for the three months ended June 30, 2013 are as follows:

	Net Gains (Losses) on Cash Flow Hedges
	(In thousands)
Balance at April 1:	$(3,838)
Other comprehensive income before reclassification	6,091
Amounts reclassified from accumulated other comprehensive income	(544)
New current-period other comprehensive income	5,547
Balance at June 30:	$1,709

Amounts reclassified from accumulated other comprehensive income (loss) into the Unaudited Condensed Consolidated Statements of Income for the three months ended June 30, 2013 are as follows:

	Amount	Affected Line Item in the Statement Where Net Income is Presented
	(In thousands)	
Net gains (loss) on cash flow hedges		
Commodity derivatives	$(823)	Oil and natural gas revenues
Commodity derivatives	1,717	Gain on derivatives not designated as hedges and hedge ineffectiveness, net
	894	Total before tax
	(350)	Tax expense
Total reclassification for the period	$544	Net of tax

Changes in accumulated other comprehensive income (loss) by component, net of tax, for the six months ended June 30, 2013 are as follows:

	Net Gains (Losses) on Cash Flow Hedges
	(In thousands)
Balance at January 1:	$7,587
Other comprehensive income before reclassification	(3,820)
Amounts reclassified from accumulated other comprehensive income	(2,058)
New current-period other comprehensive income	(5,878)
Balance at June 30:	$1,709

Table of Contents

Amounts reclassified from accumulated other comprehensive income (loss) into the Unaudited Condensed Consolidated Statements of Income for the six months ended June 30, 2013 are as follows:

	Amount	Affected Line Item in the Statement Where Net Income is Presented
	(In thousands)	
Net gains (loss) on cash flow hedges		
Commodity derivatives	$3,008	Oil and natural gas revenues
Commodity derivatives	368	Gain on derivatives not designated as hedges and hedge ineffectiveness, net
	3,376	Total before tax
	(1,318)	Tax expense
Total reclassification for the period	$2,058	Net of tax

Table of Contents

NOTE 12 – INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services:

- Oil and natural gas,
- Contract drilling, and
- Mid-stream

The oil and natural gas segment is engaged in the development, acquisition, and production of oil, NGLs, and natural gas properties. The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells and the mid-stream segment is engaged in the buying, selling, gathering, processing, and treating of natural gas and NGLs.

We evaluate each segment's performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization, and impairment. Our oil and natural gas production outside the United States is not significant.

The following table provides certain information about the operations of each of our segments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Revenues:				
Oil and natural gas	$198,498	$164,799	$386,705	$318,408
Contract drilling	135,782	118,660	260,040	238,013
Elimination of inter-segment revenue	(21,504)	(13,655)	(39,162)	(25,480)
Contract drilling net of inter-segment revenue	114,278	105,005	220,878	212,533
Gas gathering and processing	116,354	92,910	236,714	173,066
Elimination of inter-segment revenue	(23,699)	(22,293)	(50,878)	(45,054)
Gas gathering and processing net of inter-segment revenue	92,655	70,617	185,836	128,012
Total revenues	$405,431	$340,421	$793,419	$658,953
Operating income:				
Oil and natural gas	$82,530	$64,470	$170,642	$123,058
Contract drilling	27,545	23,507	51,946	47,773
Gas gathering and processing	3,898	2,846	6,528	3,675
Total operating income (1)	113,973	90,823	229,116	174,506
General and administrative	(10,600)	(9,679)	(20,237)	(18,352)
Gain on disposition of assets	195	3,483	9,621	3,399
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	(10,709)	16,344	(29,075)	10,420
Interest expense, net	(4,131)	(4,591)	(7,921)	(8,152)
Other	(49)	(91)	71	(157)
Income before income taxes	$88,679	$96,289	$181,575	$161,664

(1) Operating income is total operating revenues less operating expenses, depreciation, depletion, amortization, and impairment and does not include general corporate expenses, gain on disposition of assets, gain (loss) on

non-designated hedges and hedge ineffectiveness, interest expense, other income (loss), or income taxes.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Unit Corporation

We have reviewed the accompanying Unaudited Condensed Consolidated Balance Sheets of Unit Corporation and its subsidiaries as of June 30, 2014, and the related Unaudited Condensed Consolidated Statements of Income and Comprehensive Income for the three and six-month periods ended June 30, 2014 and 2013 and the Unaudited Condensed Consolidated Statements of Cash Flows for the six-month periods ended June 30, 2014 and 2013. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2013, and the related consolidated statements of income, shareholders' equity, and of cash flows for the year then ended (not presented herein), and in our report dated February 25, 2014, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2013, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
August 5, 2014

Table of Contents

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis (MD&A) provides an understanding of our operating results and financial condition by focusing on changes in certain key measures from year to year. We have organized MD&A into the following sections:

- General;
- Business Outlook;
- Executive Summary;
- Financial Condition and Liquidity;
- New Accounting Pronouncements; and
- Results of Operations.

Please read the following discussion and our unaudited condensed consolidated financial statements and related notes with the information contained in our most recent Annual Report on Form 10-K.

Unless otherwise indicated or required by the content, when used in this report the terms "company," "Unit," "us," "our," "we," and "its" refer to Unit Corporation or, as appropriate, one or more of its subsidiaries.

General

We operate, manage, and analyze our results of operations through our three principal business segments:

- Oil and Natural Gas – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our own account.
- Contract Drilling – carried out by our subsidiary Unit Drilling Company and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
- Mid-Stream – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account.

Business Outlook

Our current 2014 capital budget for all of our business segments forecasts a 33% increase over our 2013 capital expenditures, excluding acquisitions. Our oil and natural gas segment's capital budget is $718.0 million, a 31% increase over 2013, excluding acquisitions and ARO liability. Our drilling segment's capital budget is $132.0 million, a 105% increase over 2013. Our mid-stream segment's capital budget is $78.0 million, a 19% decrease from 2013, excluding capital leases. New and continued projects are discussed further in the Executive Summary.

Our 2014 current capital budget is based on realized prices for the year of $90.08 per barrel of oil, $29.45 per barrel of NGLs, and $3.77 per Mcf of natural gas. This budget is subject to possible periodic adjustments for various reasons including changes in commodity prices and industry conditions. Funding for the budget will come primarily from internally generated cash flow and, if necessary, borrowings under our credit agreement.

As discussed in other parts of this report, the success of our consolidated business, as well as that of each of our three operating segments, depends, to a large extent, on: the prices we receive for and the amount of our oil, NGLs, and natural gas production; the demand for oil, NGLs, and natural gas; and, the demand for our drilling rigs which, in turn, influences the amounts we can charge for the use of those drilling rigs. Although all of our current operations are located within the United States, events outside the United States can and do have an impact on us and our industry.

In addition to their direct impact on us, low commodity prices–if sustained for a long period of time–could impact the liquidity of some of our industry partners and customers which, in turn, could limit their ability to meet their financial obligations to us.

Executive Summary

Oil and Natural Gas

Second quarter 2014 production from our oil and natural gas segment was 4,618,000 barrels of oil equivalent (Boe), a 10% increase over the first quarter of 2014 and a 12% increase over the second quarter of 2013. The increase over the first

Table of Contents

quarter of 2014 was primarily due to production associated with new wells and the impact of weather conditions, mechanical issues, and fewer days had on the first quarter. The increase over the second quarter of 2013 came primarily from production associated with new wells.

Second quarter 2014 oil and natural gas revenues increased 5% over the first quarter of 2014 and increased 20% over the second quarter of 2013. The increase over the first quarter of 2014 was due primarily to increased production coupled with higher oil prices somewhat offset by lower natural gas and NGLs prices. The increase over the second quarter of 2013 was due primarily to increased production along with higher natural gas prices.

Our oil prices for the second quarter of 2014 increased 3% compared to the first quarter of 2014 and decreased 1% from the second quarter of 2013. Our NGLs prices decreased 24% and 1% from the first quarter of 2014 and second quarter of 2013, respectively. Our natural gas prices decreased 4% from the first quarter of 2014 and increased 11% over the second quarter of 2013.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) increased 4% and 28% over the first quarter of 2014 and the second quarter of 2013, respectively. The increases were due primarily to increases in production partially offset by lower liquids prices and increases in lease operating expenses. Additionally, direct profit was reduced in the second quarter of 2014 compared to the first quarter of 2014 due to higher gross production tax credits in the first quarter. The first quarter of 2014 included refunds for production tax credits attributable to certain types of gas wells of $7.9 million compared to $3.8 million during the second quarter of 2014.

Operating cost per Boe produced for the second quarter of 2014 was essentially unchanged compared to the first quarter of 2014 and decreased 12% from the second quarter of 2013. Costs were higher between the second and first quarter of 2014 primarily due to lower gross production tax credits and higher lease operating expenses offset by lower salt water disposal expense. Second quarter 2014 costs were essentially unchanged compared to the second quarter of 2013 due to higher lease operating expenses partially offset by higher gross production tax credits and lower saltwater disposal expense.

For the remainder of 2014, we have derivative contracts covering 7,000 Bbls per day of oil production and 90,000 Mmbtu per day of natural gas production. The contracts for the oil production are swap contracts covering 3,000 Bbls per day and collars for 4,000 Bbls per day. The swap transactions are at a comparable average NYMEX prices of $91.77 per barrel. The collar transactions are at a comparable average NYMEX floor price of $90.00 and ceiling price of $96.08. The contracts for our natural gas production are swaps covering 80,000 Mmbtu per day and a collar covering 10,000 Mmbtu per day. The swap transactions are at a comparable average NYMEX price of $4.24. The collar transaction is at a comparable average NYMEX floor price of $3.75 and ceiling price of $4.37.

For 2015, we have a derivative contract covering 1,000 Bbls per day of oil production. That contract is a swap contract at an average price of $95.00 per barrel.

From January 1st through June 30, 2014, we completed drilling 85 gross wells (53.16 net wells). Our current 2014 production guidance is approximately 18.9 to 19.2 MMBoe, an increase of 13% to 15% over 2013, although actual results continue to be subject to many factors. For 2014, we plan to participate in the drilling of 180 gross wells. Excluding acquisitions and ARO liability, our oil and natural gas segment's capital budget is $718.0 million, a 31% increase over 2013.

Contract Drilling

The rate at which our drilling rigs were used (“our utilization rate”) for the second quarter 2014 was 62%, compared to 57% and 51% for the first quarter of 2014 and the second quarter of 2013, respectively.

Dayrates for the second quarter of 2014 averaged $19,904, a 1% increase over the first quarter of 2014 and a 2% increase over the second quarter of 2013. The increases were due to improving market conditions.

Direct profit (contract drilling revenue less contract drilling operating expense) for the second quarter of 2014 increased 12% and 15% over the first quarter of 2014 and the second quarter of 2013, respectively. The increases were primarily due to the increase in the number of drilling rigs operating and increased dayrates.

Operating cost per day for the second quarter of 2014 decreased 5% from the first quarter of 2014 and decreased 7% from the second quarter of 2013. The decreases were primarily due to lower per day direct costs, lower workers compensation expense, and higher utilization covering fixed indirect expense.

Table of Contents

Unit's drilling rig fleet is diverse with drilling rig capabilities ranging from the shallow to the ultra-deep. This allows us the flexibility to meet customer demands for multiple market plays. The majority of our fleet is drilling horizontal or directional wells in the Bakken Shale, Green River Basin, Permian Basin, Eagle Ford Shale, South Central Oklahoma Oil Province (SCOOP), Granite Wash, and the Cleveland, Tonkawa, and Marmaton plays. These areas cover North Dakota, Wyoming, Texas, Oklahoma, and Kansas. Our smaller drilling rigs being utilized are in shallow plays like the Mississippian in northern Oklahoma and southern Kansas. We also are working in ultra-deep gas exploration in southern Louisiana. Depending on the depth and complexity of the drilling program determines the equipment required for the contract, which affects the dayrates and margins.

Currently, we have 80 drilling rigs operating. Of the 80 operating drilling rigs, 45 are on spot market contracts and 35 are on term drilling contracts, with original terms ranging from six months to two years. Seventeen of the term contracts are up for renewal in 2014, five in the third quarter, 12 in the fourth quarter, and 18 are up for renewal in 2015. Term contracts may contain a fixed rate for the duration of the contract or provide for rate adjustments within a specific range from the existing rate.

During the first quarter of 2014, four idle 3,000 horsepower drilling rigs were sold to an unaffiliated third party. The proceeds from that sale are being used in our construction program for our new proprietary 1,500 horsepower, AC electric drilling rig, called the BOSS drilling rig. We anticipate this new drilling rig design will position us to more effectively meet the demands of our existing customers as well as allowing us to compete for the work of new customers.

During the second quarter of 2013, we sold a 2,000 horsepower electric drilling rig to an unaffiliated third-party.

The first BOSS drilling rig, which originally was placed into service with our oil and natural gas segment, has now been contracted to a third-party operator that plans to take delivery in the fourth quarter of 2014. Five additional BOSS drilling rigs have been contracted to be built for third-party operators and are expected to be placed into service during the balance of 2014 and early 2015. We have modified our building schedule for the BOSS drilling rig with the objective of staying two drilling rigs ahead of contracts in place. Not including the five BOSS drilling rigs under construction, we currently have 118 drilling rigs in our fleet. Our anticipated 2014 capital expenditures for this segment are $132.0 million, a 105% increase over 2013.

Mid-Stream

Second quarter 2014 liquids sold per day increased 7% over the first quarter of 2014 and increased 50% over the second quarter of 2013. The increases were due to new wells being connected to our systems. For the second quarter of 2014, gas processed per day increased 8% over the first quarter of 2014 and increased 17% over the second quarter of 2013. These increases are primarily due to connecting new wells to both existing and newly constructed systems. For the second quarter of 2014, gas gathered per day increased 7% over the first quarter of 2014 and was essentially unchanged compared to the second quarter of 2013. The increases over the first quarter of 2014 were primarily from new wells connected.

NGLs prices in the second quarter of 2014 decreased 14% from the prices received in the first quarter of 2014 and decreased 7% from the prices received in the second quarter of 2013. Because certain of the contracts used by our mid-stream segment for NGLs transactions are percent of proceeds (POP) contracts–under which we receive a share of the proceeds from the sale of the NGLs–our revenues from those POP contracts fluctuate based on the price of NGLs.

Direct profit (mid-stream revenues less mid-stream operating expense) for the second quarter of 2014 increased 15% over the first quarter of 2014 and increased 27% over the second quarter of 2013. The increase over the first quarter of 2014 was primarily due to lower operating expenses due to a 13% decrease in the price of gas purchased. The increase over the second quarter was primarily due to increased revenues due to the increase in the liquids sold and to a lessor extent from higher gas sales and prices. The increases in direct profit over increased revenues were somewhat offset by the higher cost of gas purchased. Total operating cost for our mid-stream segment for the second quarter of 2014 decreased 3% from the first quarter of 2014 and increased 32% over the second quarter of 2013.

At our Hemphill County, Texas facility, we are continuing to connect new wells to our system as they are drilled and completed. We are in the process of constructing a trunkline that will connect our Buffalo Wallow gathering system to our Hemphill system which will allow us the ability to process gathered production from Buffalo Wallow at our Hemphill processing facility. This trunkline will consist of approximately nine miles of pipeline with related compression and is expected to be completed by the end of 2014.

At our gathering and processing facility in Reno County, Kansas, we currently have available processing capacity of approximately 25 MMcf per day. This capacity is provided by a five MMcf per day refrigerated JT plant skid and a 20 MMcf

Table of Contents

per day turbo expander plant skid. At this facility we are continuing to connect wells to this system as they are drilled and completed.

At our Cashion facility located in central Oklahoma, producers continue to be active in this area and are drilling and completing new wells in the areas around our system. We have connected 16 new wells to our system in the first six months of 2014. With our existing processing capacity of 45 MMcf per day, we are positioned to add additional volumes with minimal future capital expenditures.

In the Mississippian play in north central Oklahoma, our Bellmon facility has total processing capacity of approximately 90 MMcf per day and we continue to connect new wells to this system as they are drilled. In the first six months of 2014, we connected 32 new wells to this system and have 50 MMcf per day of available processing capacity to connect additional volumes. We are in the process of completing several expansion projects and lateral lines that will allow us the ability to connect additional wells.

In the Appalachian region, we have 19 wells connected to the Pittsburgh Mills gathering system and are in the process of constructing the second phase of this project which will extend our pipeline north into Butler County, Pennsylvania. Right of way has been acquired and construction of phase 2 is expected to begin in the third quarter of 2014 with an expected completion date in the first quarter of 2015. This will allow us the ability to connect additional wells to our system which are scheduled for completion in early and mid-2015.

Our anticipated 2014 capital expenditures for this segment are $78.0 million, a 19% decrease from 2013, excluding capital leases.

Financial Condition and Liquidity

Summary

Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our credit agreement. The principal factors determining the amount of our cash flow are:

- the quantity of natural gas, oil, and NGLs we produce;
- the prices we receive for our natural gas, oil, and NGLs production;
- the demand for and the dayrates we receive for our drilling rigs; and
- the margins we obtain from our natural gas gathering and processing contracts.

	Six Months Ended June 30,		%
	2014	2013	Change (1)
	(In thousands except percentages)		
Net cash provided by operating activities	$325,528	$317,888	2 %
Net cash used in investing activities	$(379,107)	$(322,471)	18 %
Net cash provided by financing activities	$36,064	$4,650	NM
Net increase (decrease) in cash and cash equivalents	$(17,515)	$67	

(1) NM - A percentage calculation is not meaningful due to a percentage greater than 200.

Cash Flows from Operating Activities

Our operating cash flow is primarily influenced by the prices we receive for our oil, NGLs, and natural gas production, the quantity of oil, NGLs, and natural gas we produce, settlements of derivative contracts, third-party demand for our drilling rigs, and mid-stream services and the rates we are able to charge for these services. Our cash flows from operating activities are also impacted by changes in working capital.

Net cash provided by operating activities in the first six months of 2014 increased by $7.6 million over the first six months of 2013 due primarily to increases in profit margins in all three operating segments partially offset by changes in operating assets and liabilities related to the timing of cash receipts and disbursements.

Table of Contents

Cash Flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital expenditure program toward the exploration for and production of oil, NGLs, and natural gas. These capital expenditures are necessary to offset inherent declines in production, which is typical in the capital-intensive oil and natural gas industry.

Cash flows used in investing activities increased by $56.6 million for the first six months of 2014 compared to the first six months of 2013. The change was due primarily to an increase in capital expenditures partially offset by the proceeds received from the disposition of assets. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows provided by financing activities increased by $31.4 million for the first six months of 2014 compared to the first six months of 2013. This was primarily due to an increase in our book overdrafts, which are checks that have been issued but not presented to our bank for payment before the end of the period.

At June 30, 2014, we had unrestricted cash totaling $1.1 million and had borrowed none of the $500.0 million we had elected to then have available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

The following is a summary of certain financial information as of June 30, 2014 and 2013 and for the six months ended June 30, 2014 and 2013:

	June 30,		%
	2014	2013	Change [1]
	(In thousands except percentages)		
Working capital	$(103,284)	$9,738	NM
Long-term debt	$645,925	$715,474	(10)%
Shareholders’ equity	$2,294,687	$2,079,549	10%
Ratio of long-term debt to total capitalization	22%	26%	(15)%
Net income	$111,305	$99,213	12%

(1) NM - A percentage calculation is not meaningful due to a percentage greater than 200.

Table of Contents

The following table summarizes certain operating information:

	Six Months Ended June 30, 2014	2013	% Change
Oil and Natural Gas:			
Oil production (MBbls)	1,760	1,656	6 %
Natural gas liquids production (MBbls)	2,228	1,739	28 %
Natural gas production (MMcf)	28,881	28,107	3 %
Average oil price per barrel received	$92.95	$95.05	(2)%
Average oil price per barrel received excluding derivatives	$97.81	$91.75	7 %
Average NGLs price per barrel received	$34.57	$32.47	6 %
Average NGLs price per barrel received excluding derivatives	$34.57	$32.47	6 %
Average natural gas price per mcf received	$4.14	$3.47	19 %
Average natural gas price per mcf received excluding derivatives	$4.47	$3.53	27 %
Contract Drilling:			
Average number of our drilling rigs in use during the period	70.7	65.8	7 %
Total number of drilling rigs owned at the end of the period	118	126	(6)%
Average dayrate	$19,766	$19,590	1 %
Mid-Stream:			
Gas gathered—Mcf/day	315,116	299,582	5 %
Gas processed—Mcf/day	155,807	134,016	16 %
Gas liquids sold—gallons/day	737,353	464,483	59 %
Number of natural gas gathering systems	38	40	(5)%
Number of processing plants	14	15	(7)%

Working Capital

Typically, our working capital balance fluctuates, in part, because of the timing of our trade accounts receivable and accounts payable and the fluctuation in current assets and liabilities associated with the mark to market value of our derivative activity. We had negative working capital of $103.3 million and positive working capital of $9.7 million as of June 30, 2014 and 2013, respectively. The effect of our derivative contracts decreased working capital by $15.8 million as of June 30, 2014 and increased working capital by $7.9 million as of June 30, 2013.

Impact of Prices for Our Oil, NGLs, and Natural Gas

Any significant change in oil, NGLs, or natural gas prices has a material effect on our revenues, cash flow, and the value of our oil, NGLs, and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances, and by worldwide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our first six months of 2014 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of derivatives, would result in a corresponding $461,000 per month ($5.5 million annualized) change in our pre-tax operating cash flow. The average price we received for our natural gas production, including the effect of derivatives, during the first six months of 2014 was $4.14 compared to $3.47 for the first six months of 2013. Based on our first six months of 2014 production, a $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $284,000 per month ($3.4 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices, without the effect of derivatives, would have a $357,000 per month ($4.3 million annualized) change in our pre-tax operating cash flow. In the first six months of 2014, our average oil price per barrel received, including the effect of derivatives, was $92.95 compared with an average oil price, including the effect of derivatives, of $95.05 in the first six months of 2013 and our first six months of 2014 average NGLs price per barrel received, including the effect of derivatives, was $34.57 compared with an average NGLs price per barrel of $32.47 in the first six months of 2013.

Because commodity prices affect the value of our oil, NGLs, and natural gas reserves, declines in those prices can result in a decline in the carrying value of our oil and natural gas properties. At June 30, 2014, the 12-month average unescalated prices were $100.27 per barrel of oil, $47.77 per barrel of NGLs, and $4.11per Mcf of natural gas, then adjusted for price differentials. We were not required to take a write-down in the second quarter of 2014. If there are declines in the 12-month average prices, we may be required to record write-downs in future periods.

Price declines can also adversely affect the semi-annual determination of the amount we can borrow under our credit agreement since that determination is based mainly on the value of our oil, NGLs, and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

Our natural gas production is sold to intrastate and interstate pipelines as well as to independent marketing firms and gatherers under contracts with terms generally ranging anywhere from one month to five years. Our oil production is sold to independent marketing firms generally in six month increments.

Contract Drilling

Many factors influence the number of drilling rigs we are working at any given time as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs in our areas of operation, competition from other drilling contractors, the prevailing prices for oil, NGLs, and natural gas, availability and cost of labor to run our drilling rigs, and our ability to supply the equipment needed.

Competition to keep qualified labor continues to be an issue we face in this segment. We do not believe that this shortage of qualified labor will keep us from working additional rigs, but it could cause some delays in the time needed to crew the new drilling rigs. Beginning in third quarter 2014, we increased compensation for drilling personnel in Oklahoma, Texas Panhandle, and the Gulf Coast.

Today, almost all of our working drilling rigs are drilling horizontal or directional wells for oil and NGLs. The size of the drilling rig used in these plays will vary depending on a number of factors such as the depth to be drilled and the projected length of the horizontal part of the well. For example, operators drilling in shallower oil plays like the Mississippian play in northern Oklahoma and southern Kansas tend to use drilling rigs with lower horsepower which in turn command lower dayrates and margins. But deeper wells combined with improving technology and longer horizontal laterals require drilling rigs with higher horsepower in plays such as the Granite Wash play in western Oklahoma and the Texas panhandle. All of these factors ultimately affect the demand and mix of the type of drilling rigs used by our customers. The future demand for and the availability of drilling rigs to meet that demand will have an impact on our future dayrates. For the first six months of 2014, our average dayrate was $19,766 per day compared to $19,590 per day for the first six months of 2013. The average number of our drilling rigs used in the first six months of 2014 was 70.7 drilling rigs (60%) compared with 65.8 drilling rigs (52%) in the first six months of 2013. Based on the average utilization of our drilling rigs during the first six months of 2014, a $100 per day change in dayrates has a $7,070 per day ($2.6 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our oil and natural gas segment. Depending on the timing of those services, some of those services are deemed to be associated with the acquisition of an ownership interest in the property. Accordingly, revenues and expenses for those drilling services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $39.2 million and $25.5 million for the six months of 2014 and 2013, respectively, from our contract drilling segment and eliminated the associated operating expense of $26.8 million and $18.4 million during the six months of 2014 and 2013, respectively, yielding $12.4 million and $7.1 million during the six months of 2014 and 2013, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Mid-Stream Operations

Our mid-stream segment is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas. It operates three natural gas treatment plants, 14 processing plants, 38 gathering systems, and approximately 1,500 miles of pipeline. It operates in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. This segment enhances our ability to gather and market not only our own natural gas and NGLs but also that owned by third parties and serves as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During the first six months of 2014 and 2013, our mid-stream operations purchased $45.8 million and $41.3 million, respectively, of our natural gas production and NGLs, and provided gathering and transportation services of $5.1 million and $3.8 million, respectively. Intercompany revenue

Table of Contents

from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our unaudited condensed consolidated financial statements.

This segment gathered an average of 315,116 Mcf per day in the first six months of 2014 compared to 299,582 Mcf per day in the first six months of 2013. It processed an average of 155,807 Mcf per day in the first six months of 2014 compared to 134,016 Mcf per day in the first six months of 2013. The amount of NGLs sold was 737,353 gallons per day in the first six months of 2014 compared to 464,483 gallons per day in the first six months of 2013. Gas gathering volumes per day in the first six months of 2014 increased 5% compared to the first six months of 2013 primarily from an increase in the number of wells connected to our systems between the comparative periods. Processed volumes increased 16% over the comparative six months and NGLs sold increased 59% over the comparative period due primarily to new wells connected.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. Under our Senior Credit Agreement (credit agreement), the amount available to be borrowed is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount of $900.0 million. Our current commitment amount is $500.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. The credit agreement matures as of September 13, 2016. In connection with the most recent amendment of the credit agreement, we paid $1.5 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement. At June 30, 2014 and July 25, 2014, we did not have any borrowings under our credit agreement.

The current lenders under our credit agreement and their respective participation interests are as follows:

Lender	Participation Interest	
BOK (BOKF, NA, dba Bank of Oklahoma)	17	%
BBVA Compass Banks	17	%
Bank of Montreal	15	%
Bank of America, N.A.	15	%
Comerica Bank	8	%
Crédit Agricole Corporate and Investment Bank, London Branch	8	%
Wells Fargo Bank, National Association	8	%
Canadian Imperial Bank of Commerce	8	%
The Bank of Nova Scotia	4	%
	100	%

The amount of the borrowing base–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. Effective with the April 2014 redetermination, the lenders of our credit agreement approved an increase in our borrowing base to $900.0 million from $800.0 million. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the credit agreement that in any event cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at anytime, without a premium or penalty.

We can use borrowings for financing general working capital requirements for (a) exploration, development, production, and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

Table of Contents

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of June 30, 2014, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. We have issued and outstanding an aggregate principal amount of $650.0 million, 6.625% senior subordinated notes (the Notes). The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021. In connection with the issuance of the Notes, we incurred $14.7 million of fees that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantor, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors, and the Trustee (as supplemented, the 2011 Indenture), establishing the terms and providing for the issuance of the Notes. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

The Notes are guaranteed by our 100% owned domestic direct and indirect subsidiaries (the Guarantors). Unit, as the parent company, has no independent assets or operations. These guarantees (registered under the registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from any of our subsidiaries through dividends, loans, advances, or otherwise.

At any time before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of June 30, 2014.

Capital Requirements

Oil and Natural Gas Segment Dispositions, Acquisitions, and Capital Expenditures. Most of our capital expenditures for this segment are discretionary and directed toward future growth. Any decision to increase our oil, NGLs, and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential, and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 85 gross wells (53.16 net wells) in the first six months of 2014 compared to 61 gross wells (37.27 net wells) in the first six months of 2013. Total capital expenditures for oil and gas properties on the full cost method for the first six months of 2014 by this segment, excluding a $15.4 million reduction in the ARO liability, totaled $355.0 million. Total capital expenditures for the first six months of 2013, excluding a $11.9 million reduction in the ARO liability, totaled $238.2 million.

Table of Contents

Currently we plan to participate in drilling approximately 180 gross wells in 2014 and our total estimated capital expenditures (excluding any possible acquisitions) for this segment are approximately $718.0 million. Whether we are able to drill the full number of wells planned is dependent on a number of factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

Contract Drilling Segment Dispositions, Acquisitions, and Capital Expenditures. During the first quarter of 2014, we sold four idle 3,000 horsepower drilling rigs to an unaffiliated third-party. The proceeds from that sale are being used in our construction program for our new proprietary 1,500 horsepower, AC electric drilling rig, called the BOSS drilling rig. We anticipate this new drilling rig design will position us to more effectively meet the demands of our existing customers as well as allowing us to compete for the work of new customers.

During the second quarter of 2013, we sold a 2,000 horsepower electric drilling rig to an unaffiliated third-party.

The first BOSS drilling rig, which originally was placed into service with our oil and natural gas segment, has now been contracted to a third-party operator that plans to take delivery in the fourth quarter of 2014. Five additional BOSS drilling rigs have been contracted to be built for third-party operators and are expected to be placed into service during the balance of 2014 and early 2015. We have modified our building schedule for the BOSS drilling rig with the objective of staying two drilling rigs ahead of contracts in place. Not including the five BOSS drilling rigs under construction, we currently have 118 drilling rigs in our fleet.

Our anticipated 2014 capital expenditures for this segment are $132.0 million. At June 30, 2014, we had commitments to purchase approximately $33.2 million for drilling equipment over the next twelve months. We have spent $74.2 million for capital expenditures, including $39.1 million for the BOSS drilling rigs during the first six months of 2014, compared to $21.2 million in total capital expenditures in the first six months of 2013.

Mid-Stream Acquisitions and Capital Expenditures. At our Hemphill County, Texas facility, we are continuing to connect new wells to our system as they are drilled and completed. We are in the process of constructing a trunkline that will connect our Buffalo Wallow gathering system to our Hemphill system which will allow us the ability to process gathered production from Buffalo Wallow at our Hemphill processing facility. This trunkline will consist of approximately nine miles of pipeline with related compression and is expected to be completed by the end of 2014.

At our gathering and processing facility in Reno County, Kansas, we currently have available processing capacity of approximately 25 MMcf/d. This capacity is provided by a five MMcf per day refrigerated JT plant skid and a 20 MMcf per day turbo expander plant skid. At this facility we are continuing to connect wells to this system as they are drilled and completed.

At our Cashion facility located in central Oklahoma, producers continue to be active in this area and are drilling and completing new wells in the areas around our system. We have connected 16 new wells to our system in the first six months of 2014. With our existing processing capacity of 45 MMcf/d, we are positioned to add additional volumes with minimal future capital expenditures.

In the Mississippian play in north central Oklahoma, our Bellmon facility has total processing capacity of approximately 90 MMcf/d and we continue to connect new wells to this system as they are drilled. In the first six months of 2014, we connected 32 new wells to this system and have 50 MMcf/d of available processing capacity to connect additional volumes. We are in the process of completing several expansion projects and lateral lines that will allow us the ability to connect additional wells.

In the Appalachian region, we have 19 wells connected to the Pittsburgh Mills gathering system and are in the process of constructing the second phase of this project which will extend our pipeline north into Butler County, Pennsylvania. Right of way has been acquired and construction of phase 2 is expected to begin in the third quarter of 2014 with an expected completion date in the first quarter of 2015. This will allow us the ability to connect additional wells to our system which are scheduled for completion in early and mid-2015.

During the first six months of 2014, our mid-stream segment incurred $16.3 million in capital expenditures, excluding $26.5 million for capital leases added during the second quarter of 2014, as compared to $50.2 million in the first six months of 2013. For 2014, our estimated capital expenditures (excluding capital leases) are $78.0 million.

Table of Contents

Contractual Commitments

At June 30, 2014, we had certain contractual obligations including the following:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Long-term debt [1]	$946,010	$43,062	$86,125	$86,125	$730,698
Operating leases [2]	8,348	5,905	2,423	20	—
Capital lease interest, maintenance, and future contract obligations[3]	18,180	2,990	5,711	5,156	4,323
Drill pipe, drilling components, and equipment purchases [4]	33,174	33,174	—	—	—
Enterprise Resource Planning software obligations [5]	2,861	2,375	486	—	—
Total contractual obligations	$1,008,573	$87,506	$94,745	$91,301	$735,021

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(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our June 30, 2014 interest rates of 6.625% for the Notes.

(2) We lease office space or yards in Edmond, Oklahoma City, and Tulsa, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through September, 2017. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(3) Maintenance and interest payments are included in our capital lease agreements. The capital leases are discounted using annual rates of 4.00%. Total maintenance and interest remaining are $12.3 million and $4.2 million, respectively. We also have a signed contract that begins in September 2014. The present value of the principal payments for this contract is $1.7 million.

(4) We have committed to pay $33.2 million for drilling equipment over the next twelve months.

(5) We have committed to pay $2.4 million for Enterprise Resource Planning software and $0.5 million for maintenance for one year following implementation.

Table of Contents

At June 30, 2014, we also had the following commitments and contingencies that could create, increase, or accelerate our liabilities:

	Estimated Amount of Commitment Expiration Per Period				
Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan [1]	$3,984	Unknown	Unknown	Unknown	Unknown
Separation benefit plans [2]	$10,357	$388	Unknown	Unknown	Unknown
Derivative liabilities – commodity hedges	$16,165	$15,839	$326	$—	$—
Asset retirement liability [3]	$120,591	$3,118	$39,078	$6,029	$72,366
Gas balancing liability [4]	$3,775	Unknown	Unknown	Unknown	Unknown
Repurchase obligations [5]	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability[6]	$18,868	$7,928	$2,665	$1,277	$6,998
Capital leases obligations [7]	$25,799	$3,144	$6,678	$7,233	$8,744

(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death, or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Unaudited Condensed Consolidated Balance Sheets, at the time of deferral.

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive certain claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. Currently there are no participants in the Senior Plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company. On December 31, 2008, all these plans were amended to bring the plans into compliance with Section 409A of the Internal Revenue Code of 1986, as amended.

(3) When a well is drilled or acquired, under "Accounting for Asset Retirement Obligations," we record the discounted fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for those properties we believe do not have sufficient oil, NGLs, and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2011. One of our subsidiaries serves as the general partner of each of these programs. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the

Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $8,000 in 2013 through the first six months. There have been no repurchases in 2014 through the first six months.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.

(7) The amount includes commitments under capital lease arrangements for compressors in our mid-stream segment.

Derivative Activities

Periodically we enter into derivative transactions locking in the prices to be received for a portion of our oil, NGLs, and natural gas production. In August 2012, we determined on a prospective basis, to enter into economic hedges without electing cash flow hedge accounting. All of our previous cash flow hedges expired as of December 31, 2013. Any change in fair value on all commodity derivatives we have entered into are now reflected in the income statement and not in accumulated other comprehensive income.

Commodity Derivatives. Our commodity derivatives are intended to reduce our exposure to price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our

Table of Contents

view of current and future market conditions. At June 30, 2014, based on our second quarter 2014 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Mark-to-Market	
	2014	2015
Daily oil production	67 %	10 %
Daily natural gas production	55 %	— %

With respect to the commodities subject to derivative contracts, these contracts limits the risk of adverse downward price movements. However, it also limits increases in future revenues that would otherwise result from price movements above the contracted prices.

The use of derivative transactions carries with it the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our June 30, 2014 evaluation, we believe the risk of non-performance by our counterparties is not material. At June 30, 2014, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	June 30, 2014
	(In millions)
Bank of Montreal	$(11.5)
The Bank of Nova Scotia	(4.0)
Canadian Imperial Bank of Commerce	(0.7)
Total assets (liabilities)	$(16.2)

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Unaudited Condensed Consolidated Balance Sheets. At June 30, 2014, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative liabilities of $15.8 million and $0.3 million. At June 30, 2013, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $9.9 million and $4.9 million, respectively, and current derivative liabilities of $0.9 million.

For our economic hedges that we did not apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net in our Unaudited Condensed Consolidated Statements of Income. The commodity derivative instruments we had under cash flow accounting expired as of December 2013. Previous changes in the fair value of derivatives designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, were recorded in OCI until the hedged item was recognized into earnings. When the hedged item is recognized into earnings, it was reported in oil and natural gas revenues. Any change in fair value resulting from ineffectiveness was recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net. These gains (losses) at June 30 are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net:				
Gain (loss) on derivatives not designated as hedges, included are amounts settled during the period of ($9,084), ($181), ($17,955), and $859 respectively	$(10,709)	$14,627	$(29,075)	$10,052
	—	1,717	—	368

Gain (loss) on ineffectiveness of cash flow hedges	$(10,709)	$16,344	$(29,075)	$10,420

Stock and Incentive Compensation

During the first six months of 2014, we granted awards covering 452,110 shares of restricted stock. These awards had an estimated fair value as of their grant date of $23.3 million. Compensation expense will be recognized over the three year vesting periods, and during the six months of 2014, we recognized $3.7 million in compensation expense and capitalized $0.6 million for these awards. During the first six months of 2014, we recognized compensation expense of $8.3 million for all of

Table of Contents

our restricted stock, stock options, and SAR grants and capitalized $1.8 million of compensation cost for oil and natural gas properties.

Insurance

We are self-insured for certain losses relating to workers' compensation, general liability, control of well, and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $50,000 to $1.5 million. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. There is no assurance that our insurance coverage will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover all Texas drilling operations in lieu of covering them under Texas Workers' Compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles, or any combination of these rather than pay higher premiums.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships

We are the general partner of 16 oil and natural gas partnerships which were formed privately or publicly. Each partnership's revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision, and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. For the first six months of 2014 and 2013, the total we received for all of these fees was $0.2 million and $0.3 million, respectively. Our proportionate share of assets, liabilities, and net income (loss) relating to the oil and natural gas partnerships is included in our unaudited condensed consolidated financial statements.

New Accounting Pronouncements

Compensation - Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide that a Performance Target Could Be Achieved after the Requisite Service Period. The FASB has issued ASU 2014-12, the amendments in the ASU require that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. A reporting entity should apply existing guidance in Topic 718, Compensation – Stock Compensation, as it relates to awards with performance conditions that affect vesting to account for such awards. The performance target should not be reflected in estimating the grant-date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved.The amendments in this ASU are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Earlier adoption is permitted. We do not have any stock compensation awards with these conditions at this time.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early application is not permitted. We are in the process of evaluating the impact it will have on our financial statements.

Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The FASB has issued ASU 2014-08, the amendments in this update change the criteria for reporting discontinued operations while enhancing disclosures in this area. It also addresses sources of confusion and inconsistent application related to financial reporting of discontinued operations guidance in U.S. GAAP. Under

Table of Contents

the new guidance, only disposals representing a strategic shift that would have a major effect on the organization's operations and financial results should be presented as discontinued operations. In addition, it requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. It also requires disclosure of pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. The updates are effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. Early adoption is permitted. We currently do not have any discontinued operations or disposals of components of an entity.

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. In July 2013, ASU 2013-11 was issued because GAAP does not include explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendment provides explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendments in this update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The amendments are applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. There was no effect on our financial position or results of operations when adopted.

Table of Contents

Results of Operations

Quarter Ended June 30, 2014 versus Quarter Ended June 30, 2013

Provided below is a comparison of selected operating and financial data:

	Quarter Ended June 30, 2014	2013	Percent Change [1]
Total revenue	$405,431,000	$340,421,000	19 %
Net income	$54,360,000	$59,007,000	(8)%
Oil and Natural Gas:			
Revenue	$198,498,000	$164,799,000	20 %
Operating costs excluding depreciation, depletion, and amortization	$44,723,000	$44,994,000	(1)%
Average oil price received (Bbl)	$94.17	$94.89	(1)%
Average NGLs price received (Bbl)	$29.99	$30.32	(1)%
Average natural gas price received (Mcf)	$4.05	$3.65	11 %
Oil production (Bbl)	950,000	859,000	11 %
NGLs production (Bbl)	1,163,000	935,000	24 %
Natural gas production (Mcf)	15,026,000	13,887,000	8 %
Depreciation, depletion and amortization rate (Boe)	$15.12	$13.20	15 %
Depreciation, depletion and amortization	$71,245,000	$55,335,000	29 %
Contract Drilling:			
Revenue	$114,278,000	$105,005,000	9 %
Operating costs excluding depreciation	$66,494,000	$63,590,000	5 %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	73.5	65.2	13 %
Average dayrate on daywork contracts	$19,904	$19,601	2 %
Depreciation	$20,239,000	$17,908,000	13 %
Mid-Stream:			
Revenue	$92,655,000	$70,617,000	31 %
Operating costs excluding depreciation and amortization	$78,648,000	$59,557,000	32 %
Depreciation and amortization	$10,109,000	$8,214,000	23 %
Gas gathered—Mcf/day	326,028	326,039	— %
Gas processed—Mcf/day	161,509	138,130	17 %
Gas liquids sold—gallons/day	762,205	508,189	50 %
General and administrative expense	$10,600,000	$9,679,000	10 %
Gain on disposition of assets	$195,000	$3,483,000	(94)%
Other income (expense):			
Interest expense, net	$(4,131,000)	$(4,591,000)	(10)%
Gain/(loss) on derivatives not designated as hedges and hedge ineffectiveness, net	$(10,709,000)	$16,344,000	(166)%
Other	$(49,000)	$(91,000)	46 %
Income tax expense	$34,319,000	$37,282,000	(8)%
Average interest rate	6.7 %	6.2 %	8 %
Average long-term debt outstanding	$648,289,000	$719,710,000	(10)%

(1) NM - A percentage calculation is not meaningful due to a percentage greater than 200.

Table of Contents

Oil and Natural Gas

Oil and natural gas revenues increased $33.7 million or 20% in the second quarter of 2014 as compared to the second quarter of 2013 due to a 12% increase in equivalent production and higher natural gas prices. In the second quarter of 2014, as compared to the second quarter of 2013, oil production increased 11%, NGLs production increased 24%, and natural gas production increased 8%. Average natural gas prices increased 11% to $4.05 per Mcf, while average oil prices decreased 1% to $94.17 per barrel and NGLs prices decreased 1% to $29.99 per barrel.

Oil and natural gas operating costs decreased $0.3 million or 1% between the comparative second quarters of 2014 and 2013 due to lower production taxes from refunds of $3.8 million attributable to high cost gas wells and saltwater disposal expenses offset partially by higher lease operating expenses and increased general and administrative expense.

Depreciation, depletion, and amortization ("DD&A") increased $15.9 million due primarily to a 15% increase in our DD&A rate and a 12% increase in equivalent production. The increase in our DD&A rate in the second quarter of 2014 compared to the second quarter of 2013 resulted primarily from increased capitalized cost on new wells drilled between periods. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

Contract Drilling

Drilling revenues increased $9.3 million or 9% in the second quarter of 2014 versus the second quarter of 2013. The increase was due primarily to a 13% increase in the average number of drilling rigs in use as well as a 2% increase in the average dayrate in the second quarter of 2014 compared to the second quarter of 2013. Average drilling rig utilization increased from 65.2 drilling rigs in the second quarter of 2013 to 73.5 drilling rigs in the second quarter of 2014.

Drilling operating costs increased $2.9 million or 5% between the comparative second quarters of 2014 and 2013. The increase was due primarily to the increase in utilization. Contract drilling depreciation increased $2.3 million or 13% also due primarily to the increase in utilization.

Mid-Stream

Our mid-stream revenues increased $22.0 million or 31% in the second quarter of 2014 as compared to the second quarter of 2013. The average price for natural gas sold increased 7% while the average price for NGLs sold decreased 7%. Gas processing volumes per day increased 17% between the comparative quarters and NGLs sold per day increased 50% between the comparative quarters primarily from new well connections. Gas gathering volumes per day were essentially unchanged between the comparative quarters.

Operating costs increased $19.1 million or 32% in the second quarter of 2014 compared to the second quarter of 2013 primarily due to a 15% increase in prices paid for natural gas purchased and a 13% increase in the per day gas volumes purchased. Depreciation and amortization increased $1.9 million, or 23%, primarily due to additional assets placed into service.

General and Administrative

General and administrative expenses increased $0.9 million or 10% in the second quarter of 2014 compared to the second quarter of 2013 primarily due to increases in the number of employees and increased employee costs.

Gain on Disposition of Assets

Gain on disposition of assets decreased $3.3 million in the second quarter of 2014 compared to the second quarter of 2013 primarily due to the sale of a drilling rig in 2013.

Table of Contents

Other Income (Expense)

Interest expense, net of capitalized interest, decreased $0.5 million between the comparative second quarters of 2014 and 2013. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the second quarter of 2014 was $8.1 million compared to $7.7 million in the second quarter of 2013, and was netted against our gross interest of $12.2 million and $12.3 million for the second quarters of 2014 and 2013, respectively. Our average interest rate increased from 6.2% to 6.7% and our average debt outstanding was $71.4 million lower in the second quarter of 2014 as compared to the second quarter of 2013 primarily due to the reduction of outstanding borrowings under our credit agreement over the comparative periods.

Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net decreased $27.1 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense decreased $3.0 million or 8% in the second quarter of 2014 compared to the second quarter of 2013 primarily due to decreased pre-tax income. Our effective tax rate was 38.7% for both of the second quarters of 2014 and 2013. Current income tax expense was $8.5 million for the second quarter of 2014 compared to $2.1 million for the second quarter of 2013 with the increase primarily due to increased alternative minimum taxes. We paid $8.7 million of income taxes in the second quarter of 2014.

Table of Contents

Six Months Ended June 30, 2014 versus Six Months Ended June 30, 2013

Provided below is a comparison of selected operating and financial data:

	Six Months Ended June 30, 2014	2013	Percent Change [1]
Total revenue	$793,419,000	$658,953,000	20 %
Net income	$111,305,000	$99,213,000	12 %
Oil and Natural Gas:			
Revenue	$386,705,000	$318,408,000	21 %
Operating costs excluding depreciation, depletion, and amortization	$85,138,000	$88,032,000	(3)%
Average oil price received (Bbl)	$92.95	$95.05	(2)%
Average NGLs price received(Bbl)	$34.57	$32.47	6 %
Average natural gas price received(Mcf)	$4.14	$3.47	19 %
Oil production (Bbl)	1,760,000	1,656,000	6 %
NGLs production (Bbl)	2,228,000	1,739,000	28 %
Natural gas production (Mcf)	28,881,000	28,107,000	3 %
Depreciation, depletion and amortization rate (Boe)	$14.58	$13.08	11 %
Depreciation, depletion and amortization	$130,925,000	$107,318,000	22 %
Contract Drilling:			
Revenue	$220,878,000	$212,533,000	4 %
Operating costs excluding depreciation	$130,298,000	$129,592,000	1 %
Percentage of revenue from daywork contracts	100 %	100 %	— %
Average number of drilling rigs in use	70.7	65.8	7 %
Average dayrate on daywork contracts	$19,766	$19,590	1 %
Depreciation	$38,634,000	$35,168,000	10 %
Mid-Stream:			
Revenue	$185,836,000	$128,012,000	45 %
Operating costs excluding depreciation and amortization	$159,608,000	$108,967,000	46 %
Depreciation and amortization	$19,700,000	$15,370,000	28 %
Gas gathered—Mcf/day	315,116	299,582	5 %
Gas processed—Mcf/day	155,807	134,016	16 %
Gas liquids sold—gallons/day	737,353	464,483	59 %
General and administrative expense	$20,237,000	$18,352,000	10 %
Gain on disposition of assets	$9,621,000	$3,399,000	183 %
Other income (expense):			
Interest expense, net	$(7,921,000)	$(8,152,000)	3 %
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	$(29,075,000)	$10,420,000	NM
Other	$71,000	$(157,000)	145 %
Income tax expense	$70,270,000	$62,451,000	13 %
Average interest rate	6.7 %	6.3 %	6 %
Average long-term debt outstanding	$649,179,000	$719,443,000	(10)%

(1) NM - A percentage calculation is not meaningful due to a percentage greater than 200.

43

Table of Contents

Oil and Natural Gas

Oil and natural gas revenues increased $68.3 million or 21% in the first six months of 2014 as compared to the first six months of 2013 due to a 9% increase in equivalent production and higher natural gas and NGLs prices. In the first six months of 2014, as compared to the first six months of 2013, oil production increased 6%, NGLs production increased 28%, and natural gas production increased 3%. Average natural gas prices increased 19% to $4.14 per Mcf, NGLs prices increased 6% to $34.57 per barrel, and oil prices decreased 2% to $92.95 per barrel.

Oil and natural gas operating costs decreased $2.9 million or 3% between the comparative first six months of 2014 and 2013 due primarily to a decrease in gross production taxes from refunds of $11.7 million attributable to high cost gas wells partially offset by higher lease operating expenses from the addition of new wells.

DD&A increased $23.6 million between the comparative periods due primarily to a 11% increase in our DD&A rate and a 9% increase in equivalent production. The increase in our DD&A rate in the first six months of 2014 compared to the first six months of 2013 resulted primarily from increased capitalized cost on new wells drilled between periods. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

Contract Drilling

Drilling revenues increased $8.3 million or 4% in the first six months of 2014 versus the first six months of 2013. The increase was due primarily to a 7% increase in the average number of drilling rigs in use and a 1% increase in the average dayrate in the first six months of 2014 compared to the first six months of 2013. Average drilling rig utilization increased from 65.8 drilling rigs in the first six months of 2013 to 70.7 drilling rigs in the first six months of 2014.

Drilling operating costs increased $0.7 million or 1% between the comparative first six months of 2014 and 2013. The increase was due primarily to the increase in utilization. Contract drilling depreciation increased $3.5 million or 10% also due primarily to the increase in utilization.

Mid-Stream

Our mid-stream revenues increased $57.8 million or 45% for the first six months of 2014 as compared to the first six months of 2013. Gas processing volumes per day increased 16% between the comparative periods and NGLs sold per day increased 59% between the comparative periods primarily from new well connections. Gas gathering volumes per day increased 5% primarily from new well connections.

Operating costs increased $50.6 million or 46% in the first six months of 2014 compared to the first six months of 2013 primarily due to a 26% increase in prices paid for natural gas purchased and a 13% increase in volumes purchased per day partially and by increased field operating costs due to the expansion of various systems. Depreciation and amortization increased $4.3 million, or 28%, primarily due to additional assets placed into service.

General and Administrative

General and administrative expenses increased $1.9 million or 10% in the first six months of 2014 compared to the first six months of 2013 primarily due to increases in the number of employees and increased employee costs.

Gain on Disposition of Assets

Gain on disposition of assets increased $6.2 million in the first six months of 2014 compared to the first six months of 2013 primarily due to the sale of four drilling rigs during the first six months of 2014 compared to the sale of one drilling rig during the first six months of 2013.

Table of Contents

Other Income (Expense)

Interest expense, net of capitalized interest, decreased $0.2 million between the comparative first six months of 2014 and 2013. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for the first six months of 2014 was $16.3 million compared to $16.4 million in the first six months of 2013, and was netted against our gross interest of $24.2 million and $24.5 million for the first six months of 2014 and 2013, respectively. Our average interest rate increased from 6.3% to 6.7% and our average debt outstanding was $70.3 million lower in the first six months of 2014 as compared to the first six months of 2013 primarily due to the reduction of outstanding borrowings under our credit agreement over the comparative periods.

Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net decreased $39.5 million primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense increased $7.8 million or 13% in the first six months of 2014 compared to the first six months of 2013 primarily due to increased pre-tax income. Our effective tax rate was 38.7% for the first six months of 2014 and 38.6% for the first six months of 2013. Current income tax expense was $18.3 million for the first six months of 2014 compared to $4.6 million for the first six months of 2013 with the increase primarily due to increased alternative minimum taxes. We paid $15.8 million of income taxes in the first six months of 2014.

Safe Harbor Statement

This report, including information included in, or incorporated by reference from, future filings by us with the SEC, as well as information contained in written material, press releases, and oral statements issued by or on our behalf, contain, or may contain, certain statements that are “forward-looking statements” within the meaning of federal securities laws. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events, or developments which we expect or anticipate will or may occur in the future are forward-looking statements. The words “believes,” “intends,” “expects,” “anticipates,” “projects,” “estimates,” “predicts,” a similar expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, such things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the amount of wells we plan to drill or rework;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;
- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results;

- our ability to timely secure third-party services used in completing our wells;
- our ability to transport or convey our oil or natural gas production to established pipeline systems;
- impact of federal and state legislative and regulatory initiatives relating to hydrocarbon fracturing impacting our costs and increasing operating restrictions or delays as well as other adverse impacts on our business;
- our projected production guidelines for the year;
- our anticipated capital budgets;
- the number of wells our oil and natural gas segment plans to drill during the year; and
- our outlook for the demand of our new drilling rig, the BOSS drilling rig.

Table of Contents

These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from our expectations, including:

- the risk factors discussed in this report and in the documents we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases in commodity prices; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

A more thorough discussion of forward-looking statements with the possible impact of some of these risks and uncertainties is provided in our Annual Report on Form 10-K filed with the SEC. We encourage you to get and read that document.

Item 3. Quantitative and Qualitative Disclosure About Market Risk

Our operations are exposed to market risks primarily because of changes in commodity prices and interest rates.

Commodity Price Risk. Our major market risk exposure is in the price we receive for our oil, NGLs, and natural gas production. These prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our NGLs and natural gas production. Historically, the prices we received for our oil, NGLs, and natural gas production have fluctuated and we expect these prices to continue to fluctuate. The price of oil, NGLs, and natural gas also affects the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our first six months 2014 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $461,000 per month ($5.5 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $284,000 per month ($3.4 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices, without the effect of hedging, would have a $357,000 per month ($4.3 million annualized) change in our pre-tax operating cash flow.

We use derivative transactions to manage the risk associated with price volatility. Our decisions regarding the amount and prices at which we choose to enter a contract for certain of our products is based, in part, on our view of current and future market conditions. The transactions we use include financial price swaps under which we will receive a fixed price for our production and pay a variable market price to the contract counterparty. We do not hold or issue derivative instruments for speculative trading purposes.

At June 30, 2014, the following non-designated hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jul'14 – Dec'14	Crude oil – swap	3,000 Bbl/day	$91.77	WTI – NYMEX
Jul'14 – Dec'14	Crude oil – collar	4,000 Bbl/day	$90.00-96.08	WTI – NYMEX

Jan'15 – Dec'15	Crude oil – swap	1,000 Bbl/day	$95.00	WTI – NYMEX
Jul'14 – Dec'14	Natural gas – swap	80,000 MMBtu/day	$4.24	NYMEX (HH)
Jul'14 – Dec'14	Natural gas – collar	10,000 MMBtu/day	$3.75-4.37	NYMEX (HH)

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, at our election bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Based on our average outstanding long-term debt subject to a variable rate in the first six months of 2014, a 1% increase in the floating rate would not

Table of Contents

have a material impact on our annual pre-tax cash flow. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures under Exchange Act Rule 13a-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of June 30, 2014 in ensuring the appropriate information is recorded, processed, summarized and reported in our periodic SEC filings relating to the company (including its consolidated subsidiaries) and is accumulated and communicated to the Chief Executive Officer, Chief Financial Officer, and management to allow timely decisions.

Changes in Internal Controls. There were no changes in our internal controls over financial reporting during the quarter ended June 30, 2014 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting, as defined in Rule 13a – 15(f) under the Exchange Act.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Panola Independent School District No. 4, et al. v. Unit Petroleum Company, No. CJ-07-215, District Court of Latimer County, Oklahoma.

Panola Independent School District No. 4, Michael Kilpatrick, Gwen Grego, Carla Lessel, Thelma Christine Pate, Juanita Golightly, Melody Culberson and Charlotte Abernathy are the Plaintiffs in this case and are royalty owners in oil and gas drilling and spacing units for which the our exploration segment distributes royalty. The Plaintiffs' central allegation is that our exploration segment has underpaid royalty obligations by deducting post-production costs or marketing related fees. Plaintiffs sought to pursue the case as a class action on behalf of persons who receive royalty from us for our Oklahoma production. We asserted several defenses including that the deductions are permitted under Oklahoma law. We also asserted that the case should not be tried as a class action due to the materially different circumstances that determine what, if any, deductions are taken for each lease. On December 16, 2009, the trial court entered its order certifying the class. On May 11, 2012, the Court of Civil Appeals reversed the trial court's order certifying the class. The Plaintiffs petitioned the Oklahoma Supreme Court for certiorari and on October 8, 2012, the Plaintiff's petition was denied. The Plaintiffs recently filed a second request to certify a class of royalty owners that is slightly smaller than their first attempt. We will continue to resist certification using the defenses described above, as well as new defenses based on the Court of Civil Appeals' decertification of the Plaintiffs' original class action. The merits of Plaintiffs' claims will remain stayed while class certification issues are pending.

Item 1A. Risk Factors

In addition to the other information set forth in this quarterly report, you should carefully consider the factors discussed below, if any, and in Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2013, which could materially affect our business, financial condition, or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, and/or operating results.

There have been no material changes to the risk factors disclosed in Item 1A in our Form 10-K for the year ended December 31, 2013.

47

Table of Contents

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table provides information relating to our repurchase of common stock for the three months ended June 30, 2014:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share(2)	(c) Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
April 1, 2014 to April 30, 2014	—	$—	—	—
May 1, 2014 to May 31, 2014	—	—	—	—
June 1, 2014 to June 30, 2014	88	66.22	88	—
Total	88	$66.22	88	—

(1) The shares were repurchased to remit withholding of taxes on the value of stock distributed with the second quarter 2014 vesting of restricted stock for grants previously made from our "Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012."

(2) The price paid per common share represents the closing sales price of a share of our common stock as reported by the NYSE on the day that the stock was acquired by us.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Table of Contents

Item 6. Exhibits

Exhibits:

15	Letter re: Unaudited Interim Financial Information.
31.1	Certification of Chief Executive Officer under Rule 13a – 14(a) of the Exchange Act.
31.2	Certification of Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act.
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a – 14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	Unit Corporation
Date: August 5, 2014	By: /s/ Larry D. Pinkston LARRY D. PINKSTON Chief Executive Officer and Director
Date: August 5, 2014	By: /s/ David T. Merrill DAVID T. MERRILL Senior Vice President, Chief Financial Officer, and Treasurer